TECHNICAL REVIEW DOCUMENT
For
RENEWAL TO OPERATING PERMIT 95OPAR037

Colorado Interstate Gas Company, LLC – Latigo Compressor Station
Arapahoe County
Source ID 0050055

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Revised August, October and November 2013

Reviewed by:

Operating Permit Supervisor:	Matt Burgett
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I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed operating permit proposed for this site. The current Operating Permit was issued on July 1, 2005. The expiration date for the permit was July 1, 2010. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted June 24, 2009, additional information submitted on February 13, April 3 and December 27, 2012, the May 2, 2013 response to the Division's information request, comments on the draft permit and technical review document received on September 27, 2013, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at www.colorado.gov/cdphe/airTitleV. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This source is classified as a natural gas transmission and storage facility defined under Standard Industrial Classification 4922. Natural gas is compressed and stored in wells during an injection phase. Compression is driven using natural gas-fired reciprocating engines to power the compressor units. As needed, gas is withdrawn from the storage wells and processed in several stages to separate liquid, gas and hydrocarbon phases. Hydrocarbon liquids are separated with the use of a refrigeration compressor powered by another reciprocating engine. Hydrocarbon liquids collected at each processing stage are stored and then sold for further refining. Water is removed from the gas stream with the use of an ethylene glycol dehydration system. Gas is compressed, if necessary, and transmitted to sales pipelines. The significant emission units at this facility consist of six (6) engines, an ethylene glycol dehydrator, a flare controlling various process streams, the produced water handling system, an emergency generator, process heaters and a cold cleaner solvent vat.

The facility is located in a flat, rural area approximately 7.5 miles southeast of Byers, CO. This facility is located in an area classified as attainment for all pollutants except ozone. It is classified as non-attainment for ozone and is part of the 8-hr Ozone Control Area as defined in Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. There are no Federal Class I designated areas within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the previous renewal permit has been modified to update potential to emit. Potential to emit is shown in the table below:

Unit	PM / PM_{10} / $PM_{2.5}$	SO_2	NO_X	CO	VOC	HAPs
E001	0.36	2.14E-02	149	20.2	4.3	See Table on Page 26
E002	0.36	2.14E-02	149	20.2	4.3	
E003	0.36	2.14E-02	149	20.2	4.3	
E004	0.33	1.93E-02	133.90	18.32	3.91	
E005	0.26	7.73E-03	29.74	49.05	0.39	
E006	0.26	7.73E-03	29.74	49.05	0.39	
Dehy					10.65	
Evap Ponds[1]					53	
Emerg. Gen. (E007)	9.51E-03	2.88E-04	1.24	4.84	0.06	
Fugitive VOC from equip. leaks[1]					0.37	
Flare			2.89	15.71	5.63	
Process heaters	0.98	0.08	12.95	10.88	0.71	

Unit	PM / PM_{10} / $PM_{2.5}$	SO_2	NO_X	CO	VOC	HAPs
Total	2.92	0.18	657.46	208.45	88.01	71.46

[1]Note that emissions from the evaporation ponds and equipment leaks are considered "fugitive" emissions and are not counted in determining whether a source is a "major stationary source" or a modification is a "major modification", unless the source is a listed source in Reg 3, Part D, Section II.A.24.a or as of August 7, 1980 is regulation under Section 111 or 112 of the federal Clean Air Act. Fugitive VOC emissions from the facility do not count in determining major stationary source status.

Potential to Emit (PTE) indicated in the above table is based on the following information:

Criteria Pollutant Emissions

Engines. Emissions from engines E001 thru E003 are based on permit limits or permitted fuel consumption and emission factors from AP-42, Section 3.2 (dated 7/00), Table 3.2-2. Emissions from engines E004 thru E006 are based on design rate, emission factors from AP-42, Section 3.2 (dated 7/00), Tables 3.2-2 or Table 3.2-3, as appropriate, and 8760 hours per year of operation. For the emergency generator (E007) emissions are based on design rate, emission factors (AP-42, Section 3.2 (dated 7/00), Table 3.2-3 for PM/PM_{10}/$PM_{2.5}$ and SO_2 and manufacturers for NO_X, CO and VOC) and 500 hours per year of operation (in accordance with the September 6, 1995 EPA Memo, "Calculating Potential to Emit (PTE) for Emergency Generators").

Dehy. Emissions are based on permit limits.

Flare. Emissions from the flare is based on requested emissions per December 27, 2012 submittal. Note that the condensate truck loading, which is included in the current permit (issued August 29, 2008) as a significant emission unit, is controlled by the flare.

Fugitive VOC Emissions from Equipment Leaks. Emissions are based on the information provided in the December 27, 2012 submittal. Emissions are below the APEN de minimis level, therefore CIG requested that the underlying construction permit (95AR109) for fugitive VOC emissions be cancelled.

Produced Water System (Evaporation Ponds). Emissions from the produced water system is based on requested emissions for the storage ponds in the April 3, 2012 information submittal. Note that beginning with the 2013 withdrawal season, produced water will be routed to an injection well and there will be essentially no emissions from the system. However, CIG has requested use of one storage pond in the event of back-up or emergency situation hence emissions from the ponds have been assessed.

Process Heaters and Boilers. Emissions from the process heaters and boilers are based on design rate, emission factors from AP-42, Section 1.4 (dated 3/98), Tables 1.4-1 and 1.4-2 and 8760 hours per year of operation.

Hazardous Air Pollutants (HAP)

The breakdown of HAP emissions by emission unit and individual HAP is provided on page 26 of this document. As indicated in the footnotes for the table on page 26, HAP PTE was determined as follows:

Engines E001 thru E004 (lean burn engines): HAP emissions are based on design rate, permitted annual hours of operation (or 8760 hrs/yr) and for formaldehyde emission factors from a July 2004 performance test and for other HAPs the most conservative emission factor from AP-42 or HAPCalc 2.0. Note that the HAPCalc 2.0 factors are not significantly different from the HAPCalc 3.0 factors.

Engines E005 and E006 (rich burn engines): HAP emissions are based on design rate, 8760 hrs/yr of operation and the most conservative emission factor from AP-42 or HAPCalc 2.0. Note that the HAPCalc 2.0 factors are not significantly different from the HAPCalc 3.0 factors.

Dehydrator: HAP emissions are based on the GLYCalc run used to set the permit limits, except that methanol and ethylene glycol emissions are based on stack test emission factors and permitted hours of operation.

Emergency generator (E007): HAP emissions are based on the most conservative emission factor from AP-42 or HAPCalc 2.0, design rate and 500 hours per year of operation (in accordance with the September 6, 1995 EPA Memo, “Calculating Potential to Emit (PTE) for Emergency Generators”). Note that the HAPCalc 2.0 factors are not significantly different from the HAPCalc 3.0 factors.

Produced Water System (Evaporation Ponds). HAP emissions are based on requested emissions for the storage ponds in the April 3, 2012 information submittal. Note that beginning with the 2013 withdrawal season, produced water will be routed to an injection well and there will be essentially no emissions from the system. However, CIG has requested use of one storage pond in the event of back-up or emergency situation hence HAP emissions from the ponds has been assessed.

Process Heaters: HAPS emissions are based on AP-42 emission factors (Section 1.4, dated 3/98, Table 1.4-3), design rate and 8760 hour per year of operation.

Flare: HAP emissions are based on requested emissions per December 27, 2012 submittal. Note that the condensate truck loading, which is included in the current permit (issued August 29, 2008) as a significant emission unit, is controlled by the flare.

Actual Emissions

Actual emissions are shown in the table below and are based on the data year indicated. APENs were submitted on March 25, 2011 for the engines and May 2, 2013 for the dehydrator. Emissions from the flare and evaporation ponds are based on requested emissions noted on the APENs submitted September 27, 2013 and April 3, 2012, respectively.

Emission Unit	Data Year	PM/PM_{10}/ $PM_{2.5}$	SO_2	NO_X	CO	VOC	HAPS
E001 - E003	2010 + 100%	0.51	3.00E-02	207	28.3	6	3.42
E004	2010 + 100%	0.22	1.00E-02	105.00	14.40	3.10	1.45
E005 & E006	2010 + 100%	0.13	4.00E-03	14	23.2	0.19	0.18
Dehy	2012					4.21	2.38
Evap Ponds[1]	PTE					53	51.7
Flare[2]	PTE			2.89	15.71	5.63	0.06
Total		0.86	0.04	328.89	81.61	72.13	59.19

[1]The evap ponds will be replaced with an injection well during the 2013 withdrawal season (fall), so emissions from the produced water system will be negligible when the injection well commences operation.

[2]The flare will commence operation beginning with the 2013 withdrawal season (fall).

National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories

As indicated in the above table summarizing potential emissions, the facility is a major source for HAPS and may be subject to NESHAPs for specific source categories (hereafter, referred to as “MACT requirements”). At the time of the first renewal (issued July 1, 2005) the Division considered the facility to be a minor source for HAPs. However, during an inspection in October 2008, the Division requested information regarding emissions from two produced water evaporation storage ponds (one began operation in 1983 and the other in 1986). Based on the information submitted in the renewal application on June 24, 2009, methanol emissions from the produced water tank were over 10 tons/yr making the facility a major source for HAPs. Although emissions from the evaporation ponds had not been estimated prior to 2008, the Division considers that the facility was considered a major source of HAPs from installation of the second pond and remains a major source until CIG controls emissions from the ponds and/or other equipment at this facility to keep HAP emissions below the major source level. Under the “once-in-always-in” policy for MACT requirements, sources must limit HAP emissions below the major source level by the first compliance date in order to avoid major source MACT requirements.

According to a 2011 inspection report, the Division noted that the source going to pursue permitting an injection well for the produced water and would thus no longer use the evaporation ponds. The Division requested that Colorado Interstate Gas Company, LLC (CIG) indicate whether they planned to take limits to reduce HAP emissions below the major source level and avoid major source MACT requirements for equipment with future compliance dates. In their May 2, 2013 information submittal, CIG indicated that due to the need to retain one evaporation pond as a back-up to the injection well, the Latigo facility would retain its major source status for HAP emissions.

Natural Gas Transmission and Storage (NGTS) Facility MACT (40 CFR Part 63 Subpart HHH)

The provisions in 40 CFR Part 63 Subpart HHH apply to glycol dehydrators located at major sources of HAPs. Since the facility is a major source for HAPs, the requirements in Subpart HHH apply to this facility. Under the initial rules (published in the Federal Register on June 17, 1999), as long as actual emissions of benzene are less than 0.9 megagrams per year (1,984 lbs/yr), then only recordkeeping requirements applied. Actual benzene emissions from the glycol dehydrator are below 0.9 megagrams and so only recordkeeping requirements applied to this unit.

EPA signed off on final revisions to the provisions in 40 CFR Part 63 Subpart HHH on April 17, 2012, which were published in the Federal Register on August 16, 2012 and these revisions impose BTEX limits on glycol dehydrators that were formerly exempt (i.e. dehydrators with actual benzene emissions less than 0.9 megagrams (1,984 lbs) or 283,000 standard cubic meters per day (10.0 MMscf/day)). The formerly exempt glycol dehydrators are considered small glycol dehydrators and existing (commenced construction before August 23, 2011) small glycol dehydrators have until October 15, 2015 to comply with the requirements. The appropriate requirements from 40 CFR Part 63 Subpart HHH that apply to the dehydrator will be included in the permit.

Reciprocating Internal Combustion Engines (40 CFR Part 63 Subpart ZZZZ)

The reciprocating internal combustion engine (RICE) MACT was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. Under this rulemaking only RICE that were > 500 hp and located at major sources of HAPS were subject to the requirements. Subsequent revisions were made to the RICE MACT to address new engines ≤ 500 hp located at major sources and new engines of all sizes at area sources (final rule published January 18, 2008), existing compression ignition engines ≤ 500 hp at major sources and all sizes at area sources (final rule published March 3, 2010) and existing spark ignition engines ≤ 500 hp at major sources and all sizes at area sources (final rule published August 20, 2010). Revisions have been made to the RICE MACT requirements since then; however, those revisions did not change the applicability requirements for the engines at this facility.

Engines E001 through E004 are existing (commenced construction prior to December 19, 2002) 4-stroke lean burn engines > 500 hp and are not required to meet the requirements in 40 CFR Part 63 Subparts A and ZZZZ, including the initial notification requirements (see § 63.6590(b)(3)(ii)).

Engines E005 and E006 are considered existing engines (commenced construction prior to December 19, 2002) and are subject to requirements under Subpart ZZZZ. In addition, there is one natural gas-fired emergency generator included in the insignificant activity list and this engine has been in the list since the Title V permit was initially issued on November 1, 1998, so it would qualify as existing engine (construction commenced prior to December 19, 2002). The emergency generator is less than 500 hp and is subject to work practice requirements under Subpart ZZZZ. The appropriate requirements in 40 CFR Part 63 Subpart ZZZ that apply to these engines will be included in the permit.

Organic Liquid Distribution (Non-Gasoline) MACT (40 CFR Part 63 Subpart EEEE)

Under 40 CFR Part 63 Subpart EEEE §§ 63.2334(c)(2), organic liquid distribution operations do not include activities and equipment at NGTS facilities; therefore, the organic liquid distribution MACT requirements do not apply.

Boiler MACT for Major Sources (40 CFR Part 63 Subpart DDDDD)

EPA promulgated National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (the Boiler MACT) on March 21, 2011. These requirements apply to boilers and process heaters that are located at major sources of HAPs and as such these requirements apply. There is no de minimis level specified in the requirements and there is fuel-burning equipment identified in the insignificant activity list that is potentially subject to these requirements. Since all of the fuel-burning equipment at the facility only burns natural gas, only work practice standards (i.e., boiler tune-ups) apply. As a result the process heaters that are subject to Boiler MACT requirements will be removed from the insignificant activity list and included in Section II of the permit.

Final revisions to the Boiler MACT were published in the Federal Register on January 31, 2013. The January 31, 2013 final rules have no affect on the applicability of the Boiler MACT to the boilers and process heaters at this facility.

New Source Performance Standards (NSPS)

EPA has promulgated NSPS requirements for new source categories since the issuance of the first renewal permit for this facility. NSPS requirements generally only apply to new or modified equipment and the Divisions is not aware of any modifications to existing equipment or additions of new equipment that would render equipment at this facility subject to NSPS requirements. However, because the recently promulgated NSPS requirements address equipment that may not be subject to APEN reporting or minor source construction permit requirements, the applicability of some of the newly promulgated requirements are being addressed here.

NSPS Subpart JJJJ – Stationary Spark Ignition Engines

NSPS Subpart JJJJ applies to stationary spark ignition engines that commenced construction, reconstruction or modification after June 12, 2006 and were manufactured after specified dates. The date the engine commenced construction is the date the engine was ordered by the owner/operator. Engines E001 through E006 commenced operation in the late 1970s and there is no indication that these units have been modified. As discussed under the RICE MACT, the emergency generator has been listed in the insignificant activity list since the permit was first issued in 1998 and there is no indication that this unit has been modified. Therefore, the requirements in NSPS

Subpart JJJJ do not apply to any of the engines at this facility since they all commenced construction prior to June 12, 2006.

<u>NSPS Subpart IIII – Stationary Compression Ignition Engines</u>

NSPS Subpart IIII applies to stationary compression ignition engines that commenced construction, reconstruction or modification after July 11, 2005 and were manufactured after specified dates. The date the engine commenced construction is the date the engine was ordered by the owner/operator. There are no compression ignition engines located at the Latigo Compressor Station; therefore, the requirements in NSPS Subpart IIII do not apply.

<u>NSPS Subpart OOOO – Crude Oil and Natural Gas Production, Transmission and Distribution</u>

The provisions in NSPS Subpart OOOO apply to several affected facilities at crude oil and natural gas production, transmission and distribution facilities that commenced construction, modification or reconstruction after August 23, 2011. The affected facilities under NSPS OOOO include gas wells, compressors (centrifugal and reciprocating), pneumatic controllers, storage vessels, equipment leaks associated with process units (i.e., equipment used to extract natural gas liquids from field gas) and sweetening units located at onshore natural gas processing plants. In the first case, the facility commenced operation in the late 1970s and it is not apparent that any equipment at the facility was constructed, reconstructed or modified after August 23, 2011; however, the Division has reviewed the potential applicability with respect to the individual affected facilities.

The pneumatic controllers and compressors are only affected facilities if they are located between the wellhead and the natural gas transmission and storage segment. Since this facility is a natural gas storage facility (hence part of the natural gas transmission and storage segment), any compressors or pneumatic controllers are not affected facilities, regardless of when they were constructed, reconstructed or modified.

Under the rule, gas wells are defined as “an onshore well drilled principally for production of natural gas”. While gas may be injected into wells at the Latigo Compressor Station for storage, the wells are for storage of pipeline quality natural gas, not for production of natural gas. Therefore, there are no wells at this facility that meet the definition of “gas well” under Subpart OOOO.

Equipment associated with process units and sweetening units located at onshore natural gas processing plants are affected facilities under Subpart OOOO. There are no sweetening units at this facility. Process units extract natural gas liquids from field gas, so essentially a process unit is what makes a facility an onshore natural gas processing plant. Although this facility may remove natural gas liquids from natural gas, the facility is not a gas processing plant because liquids are not extracted from field gas but from pipeline quality natural gas that absorbs hydrocarbons during storage. The Latigo

Compressor Station is a natural gas storage facility and not a gas plant; therefore, any process unit at this facility is not an affected facility, regardless of when it was constructed, reconstructed or modified.

Any storage vessels with VOC emissions greater than or equal to 6 tons/yr of VOC that commenced construction, reconstruction or modification after August 23, 2011 would be an affected facility and would be subject to the requirements in Subpart OOOO. While there is a number of storage vessels included in the insignificant activity list in the permit, these tanks have been included in the permit since it was first issued November 1, 1998. In their September 27, 2013 comments on the draft permit and technical review document, the source indicated that two tanks (T-19 and T-22) were installed in October 2010 but that there are no tanks at the facility that commenced construction, reconstruction or modification after August 23, 2011. Therefore none of the storage vessels at this facility meet the applicability date (i.e. commenced construction, reconstruction or modification after August 23, 2011) and they are not affected facilities under the requirements of Subpart OOOO.

In summary, there are no Subpart OOOO affected facilities located at the Latigo Compressor Station so the requirements in Subpart OOOO do not apply.

Note that a proposed rule was published in the Federal Register on April 12, 2012 for Subpart OOOO to reconsider certain provisions. Since no equipment at this facility is subject to the requirements of Subpart OOOO any provisions finalized due to this proposal will not affect the equipment at this facility.

Colorado Regulation No. 7, Sections XII and XVIII – Requirements for Oil and Gas Operations in the 8-hour Ozone Control Area

The applicability of the requirements in Section XII was discussed in the technical review document for the first renewal permit (issued July 1, 2005) beginning on page 12. The requirements in Section XII were revised somewhat since the first renewal permit was issued and the requirements in Section XVIII were added and so a discussion of these requirements is being included.

- Applicability and definitions (Sections XII.A and XII.B)

- Requirements for condensate collection, storing and handling (Section XII.C, D, E and F)

  As noted in the technical review document for the first renewal and in Section XII.A.1, these requirements apply to exploration and production operations, compressor stations or drip stations located upstream of a natural gas-processing plant. Since the Latigo facility receives pipeline quality natural gas (i.e. gas that has been processed), the Division considers that the condensate tanks at the Latigo facility are not subject to these requirements since they are located downstream of a natural gas processing plant.

- Requirements for gas processing plants (Section XII.G)

  As noted in the technical review document for the first renewal, although equipment at the Latigo facility is used to extract natural gas liquids, the Division considers that the Latigo facility is not a natural gas processing plant, because the gas processed is not field gas (i.e. gas that has not been treated previously). The presumption is consistent with EPA Headquarters' position as stated in their letter date June 24, 2004, re "Applicability Determination in Clarifying the Natural Gas Processing Plant Definition Under NSPS Subpart KKK" (see memo on pages 24-25).

- Glycol Dehydrators (Section XII.H)

  In the technical review document for the first renewal, the Division noted that the requirements for glycol dehydrators in Section XII.H did not apply because permitted VOC emissions for the dehydrator were below 15 tons/yr. While that is true, these requirements do not apply because the requirements in Section XII.H were intended to apply to glycol dehydrators located at facilities either located upstream or at a natural gas processing plant (i.e. would not apply to glycol dehydrators in the natural gas transmission and storage category). This facility is a natural gas storage facility which is downstream of any natural processing plant(s) and is within the natural gas transmission and storage category. As a result these requirements do not apply.

The requirements in Section XVIII were adopted in December 2008 and apply to natural gas-actuated pneumatic controllers associated with natural gas operations in the 8-hour ozone control area or any ozone nonattainment or attainment maintenance area. These requirements specifically apply to pneumatic controllers located at or upstream of a natural gas processing plant. Note that Section XVIII specifically states that upstream activities include oil and gas exploration and production operations, natural gas compressor stations and/or natural gas drip stations. As previously stated, this facility is not a natural gas processing plant and is located downstream of a natural gas processing plant, therefore, these requirements do not apply.

Colorado Regulation No. 7, Section XVI - Requirements for Engines in the 8-Hour Ozone Control Area and Section XVII – Statewide Requirements for Oil and Gas Operations

The requirements in Section XVI were adopted in March 2004 and apply to the 8-hour ozone control area. The requirements in Section XVII were adopted in December 2006 and apply statewide. The requirements in Section XVI apply to natural gas fired engines. The requirements in Section XVII include requirements for condensate tanks, glycol dehydrators and natural gas fired engines.

Condensate tank and glycol dehydrator requirements

Although actual uncontrolled emissions from condensate tanks and the glycol dehydrator are below the applicability levels in Section XVII (20 tons/yr for condensate tanks and 15 tons/yr for dehydrators), the Division considers that these requirements were intended to apply to condensate tanks and glycol dehydrators located at facilities either located upstream or at a natural gas processing plant (i.e. would not apply to glycol dehydrators or condensate tanks in the natural gas transmission and storage category). This facility is a natural gas storage facility which is downstream of any natural processing plant(s) and is within the natural gas transmission and storage category. As a result these requirements do not apply.

Engine Requirements

The requirements in Regulation No. 7, Section XVI apply to engines located in the 8-hour ozone control area and sets control requirements for engines greater than 500 hp. This facility is located in the 8-hour ozone control area and these engines are all greater than 500 hp. The provisions in Section XVI.C.4 specify that lean burn engines operating in the 8-hour ozone control area prior to June 1, 2004 are exempt from the control requirements in XVI if the owner or operator demonstrates that the cost of retrofit control technology will exceed $5,000 per ton. Such demonstrations were to be submitted prior to May 1, 2005. The source submitted a demonstration indicating that the cost of retrofit controls would exceed $5,000 per ton on April 29, 2005 and in an October 12, 2005 letter, the Division agreed that the exemption applied to engines E001 through E004. Note that in the January 30, 2007 revised Title V permit the description of engines E001 through E004 was revised to indicate that the engines were 4-cycle lean burn engines. Prior to the January 30, 2007 Title V permit, engines E001 through E004 were identified as rich burn engines.

Note that Reg 7 was revised in 2008 to include control requirements for natural-gas fired engines state-wide. These requirements are found in Section XVII.E and apply to both new and existing engines. The requirements for existing engines apply to engines that were constructed or modified before February 1, 2009 and are greater than 500 hp. The requirements are similar to the requirements for engines over 500 hp located in the 8-hour ozone control area and provides the same exemption for lean burn engines (if source demonstrates retrofit control costs are greater than $5,000 per ton the engine is exempt). Therefore, the requirements for existing engines in Reg 7, Section XVII.E.3 do not apply. The requirements for new engines depend on the date the engine commenced construction or relocation and the size of the engine. Engines E001 through E006 and the emergency generator are not new and therefore, the requirements for new engines in Section VIII.E.2 do not apply.

Compliance Assurance Monitoring (CAM) Requirements

In the technical review document for the first renewal of this permit (issued July 1, 2005), the Division indicated that CAM did not apply because none of the emission units at the facility were equipped with control devices.

In the future, engines E005 and E006 and the glycol dehydrator will be subject to emission limitations under 40 CFR Part 63 Subparts ZZZZ and HHH, respectively, for which control device(s) may be necessary. Based on 2012 data it appears that no controls will be necessary for the glycol dehydrator. In addition, the Division presumes that control devices will not be required to meet the Subpart ZZZZ requirements for engines E005 and E006. Nevertheless, as specified in 40 CFR Part 64 § 64.2(b)(1)(i), "[e]mission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act" are exempt from the CAM requirements. Therefore, even if controls were required to meet upcoming MACT requirements, CAM would not apply unless CIG took limitations to reflect the use of a control device to reduce their potential to emit.

As discussed later in this document, a flare has been added to the facility to control a number of process streams and this flare is subject to an annual VOC emission limitation. However, uncontrolled emissions from the various process streams are below the major source level, therefore, the flare is not subject to the CAM requirements.

As a result the applicability of CAM to the equipment at this facility has not changed since the first renewal (issued November 1, 1998). CAM does not apply to any emission unit at this facility.

Greenhouse Gas Emissions

The potential-to-emit of greenhouse gas (GHG) emissions from this facility is less than 100,000 TPY CO_2e. Future modifications greater than 100,000 TPY CO_2e may be subject to regulation (Regulation No. 3, Part A, I.B.44).

<u>Repealed APEN Exemptions</u>

Since the first Title V renewal permit was processed (issued July 1, 2005) the APEN exemptions for engines – limited size and hours (Reg 3, Part A, Section II.D.1.sss) and emergency generators – limited size and hours (Reg 3, Part A, Section II.D.1.ttt) was repealed. Although the specific APEN exemptions for engines and emergency generators have been repealed, these emission units are still exempt from APEN reporting requirements if actual, uncontrolled emissions are below the APEN de minimis level).

CIG submitted information on May 2, 2013 indicating that actual emissions from the emergency generator were below the APEN de minimis level (1 ton/yr for NO_X and VOC and 2 tons/yr for other criteria pollutants).

III. Discussion of Modifications Made

<u>Source Requested Modifications</u>

The source's requested modifications identified in the renewal application were addressed as follows:

June 24, 2009 Renewal Application, April 3, 2012 Additional Information Submittal and Comments on the Draft Permit and Technical Review Document Received on September 27, 2013

The source's requested modifications that were identified in the renewal application have been addressed as follows:

Page following cover

- The primary SIC and description regarding the nature of the business were revised.

Evaporation Ponds/ Produced Water System

CIG submitted information indicating that emissions from the evaporation ponds were above the APEN de minimis levels and requested that the evaporation ponds be included in the Title V permit. Following submittal of the renewal application, the source submitted a RACT analysis on August 10, 2009. In this RACT analysis, the source indicated that none of the technically feasible control options were economically reasonable.

In their April 3, 2012 additional information submittal, CIG requested increased throughput and emission limitations for the evaporation ponds since recent testing indicated a significant increase in the methanol concentrations in the pond water. Based on the RACT analysis submitted on August 10, 2009 the technically feasible control options would be economically feasible. Therefore, the Division requested that a revised RACT analysis be submitted.

In their December 27, 2012 additional information submittal, CIG indicated that they had decided to install an injection well to replace the evaporation ponds but would still want to maintain one pond for backup purposes. In their May 2, 2013 response to an information request from the Division, CIG indicated that the injection well would commence operation during the 2013 withdrawal season (fall). Emissions from produced water would be negligible with the injection well.

In their comments on the draft permit submitted on September 27, 2013, the source indicated that water would be in the ponds in 2014. In a response to questions from the Division regarding these comments, the source indicated that water is currently stored in the evaporation ponds and that water from the ponds must be pumped to the produced water system in order for it to be disposed of in the injection well. The source indicated that removal of water from the evaporation ponds cannot be done in conjunction with the recovery season due to equipment limitations but that the pond would be emptied in the summer of 2014.

The Division has included requirements to address the produced water system in Section II.5 of the permit. The permit will specify that beginning with the 2013 withdrawal season that any produced water generated during withdrawal will be routed to the injection well and that the produced water currently stored in the ponds shall be removed and routed to the injection well by August 1, 2014. The permit allows the use of the evaporation ponds as a back-up during the 2013-2014 withdrawal season and includes specific requirements in the event that water is discharged to the ponds. Use of the ponds as a back-up after the 2013-2014 withdrawal season will require that the permit be revised to include the appropriate applicable requirements for the ponds (e.g. RACT determination and emission and throughput limits).

Section II.4 – Glycol Dehydrator

With respect to the glycol dehydrator CIG specifically requested that the requirements in 40 CFR Part 63 Subpart HHH be included in the permit. Based on sampling conducted on the evaporation ponds, the Latigo facility is now a major source for HAPs. The provisions in Subpart HHH have been revised since the renewal application was submitted and the appropriate applicable requirements from Subpart HHH have been included in Condition 4.4 of the permit.

CIG also requested clarification regarding some of the dehydrator monitoring language, which was addressed as follows:

- Condition 4.1.2 was revised to indicate that extended gas sampling would be conducted “once per calendar year” rather than “annually”.

- Additional language was added to Condition 4.1.4 to clarify that GLYCalc runs are not required for months in which the unit operates less than 240 hours per month.

February 13, 2012 and December 27, 2012 Additional Information Submittals and Comments on the Draft Permit and Technical Review Document Received on September 27, 2013

The source submitted information on February 13, 2012 indicating that a temporary flare would be installed to control emissions from the third stage separator, as well as other equipment located at the facility, such as the heater treater and the condensate loading rack. CIG submitted an application on December 27, 2012 indicating that the temporary flare would become the permanent control for these process streams and submitted emission and throughput information to permit the flare. CIG notified the Division in April 2013 that the temporary flare was inoperable. It is not clear whether the flare will be repaired or replaced with a new flare but prior to beginning withdrawal in 2013 (fall of 2013), these process streams are to be controlled. The source submitted information on September 27, 2013 for the replacement flare. This is an air-assisted flare that was transferred from CIG’s Totem Compressor Station. Based on concerns from the Division regarding the emission estimation methodology in the September 27, 2013 submittal, the source submitted revised emission estimates via e-mail. The flare will be included in Section II.6 of the permit. Note that in the current permit (issued August 29, 2008), provisions for condensate truck loading are included in Section II.5 but since emissions from the condensate loading rack will be routed to the flare, provisions addressing condensate loading have been removed. Specific provisions for the flare have been addressed as follows:

- Emission limits were set based on the information in the September 27, 2013 comments on the draft permit and technical review document and information in a November 5, 2013 e-mail from the source. After reviewing the September 27, 2013 submittal, the Division required that VOC emissions from process gases be based on material balance with an assumed control efficiency of 95% and the source submitted emission estimates using this methodology on November 5, 2013 The APEN submitted with the September 27, 2013 comments on the draft permit and technical review document was red-lined to note the November 5, 2013 changes to requested VOC emissions.

- The throughput limit for the flare was set at 85.5 MMscf/yr. This is based on throughput rate of 233 Mscf/day for the process gases and 50 scf/hr for pilot gas. The throughput limit is based on 8760 hours per year of operation.

- Operating requirements were included for the flare. The Division considers that requirements similar to those in 40 CFR Part 63 Subpart A, § 63.11(b) should be included. These requirement include operating the flare at all time that emissions are vented to it, maintaining a flame in the flare at all times it is operating and operating the flare with no visible emissions.

- Performance test requirements will be included for the flare. Performance tests are required for visible emissions, Btu content of gas burned and velocity. Performance tests will be required to be conducted similar to the performance testing provisions in § 63.11(b).

- Opacity of emissions from smokeless flares shall not exceed 30% (Colorado Regulation No. 1, Section II.A.5).

<u>CAM Applicability to the flare</u>

The CAM requirements apply to an emission unit that uses a control device to achieve an emission limitation and has uncontrolled emissions above the major source level. The flare is used to control VOC emissions from a number of process streams and the flare will be subject to an annual VOC emission limitation. Since the flare is controlling number of process streams it is effectively controlling a number of "process units" (e.g., the condensate loading rack, the three stage separator). Based on the requested emission limitations for the flare, uncontrolled VOC emissions from process gases going to the flare are 111.7 tons/yr, which is above the major source level. Since these emissions are from more than one process unit it is difficult to determine whether uncontrolled emissions from any one process unit exceed the major source level. Since uncontrolled emissions are above the major source level by a relatively small amount, the Division considers that it is unlikely that uncontrolled emissions from any one process unit are above the major source level. In addition, the flare will be subject to requirements similar to those in 40 CFR Part 63 § 63.11(b), which requires continuous monitoring of the pilot flame for flares. If CAM did apply to the flare, CAM would specify continuous monitoring of the pilot flame. Since it is not clear that any one process unit has uncontrolled emissions above the major source level and the monitoring that will be included in the permit for the flare is similar to the monitoring that would be required under CAM, the Division is considering that CAM does not apply to the flare.

Emission Factors - Emissions from the flare will be estimated using the following emission factors:

Pollutant	Emission Factor	Source
NO_X	0.068 lb/MMBtu	AP-42, Section 13.5 (dated 9/91), Table 13.5-1
CO	0.37 lb/MMBtu	
VOC – pilot gas	0.14 lb/MMBtu	
VOC – process gas	131.4 lb/MMscf	Based on material balance (from February 2013 dehy inlet gas analysis submitted in a November 5, 2011 email), a maximum daily process flow rate of 233 Mscf/day and a 95% control efficiency.

The emission factors listed in the above table in units of "lb/MMBtu" will be converted to units of lb/MMscf in the permit by multiplying by a heat content of 993.2 Btu/scf. This is the heat content used in the source's emission calculations for the flare. Since the Latigo facility stores pipeline quality natural gas, the Division considers that the Btu content of the gases combusted (both pilot and process gas) are not likely to vary significantly, therefore, converting the emission factors to a lb/MMscf basis is acceptable.

Monitoring Plan – A performance test will be required for the flare for visible emissions, Btu content of gas burned and velocity. Thereafter, compliance with the visible emission requirements and Btu content requirement shall be met through periodic visible emission observations (monthly) and process gas sampling (annual). In addition, the permittee will be required to record the quantity of process gas combusted and calculate emissions monthly and use monthly throughput/emissions in rolling twelve month totals to monitor compliance with the annual limitations.

May 2, 2013 Response to Request for Information from the Division

<u>Section II.4 - Glycol Dehydrator</u>

Since the evaporation ponds will be used for back-up to the injection well, the Latigo facility is considered a major source for HAP emissions. Therefore, CIG requested in the May 2, 2013 response to an information request that the HAP limits for the glycol dehydrator be removed. In addition, CIG requested an increase in the VOC emission limit for the glycol dehydrator to include both ethylene glycol and methanol emissions. Note that GLYCalc does not predict emissions of these pollutants.   The following changes were addressed in the permit as follows:

- The VOC emission limit in Condition 4.1 was revised as requested and the single and total HAP limitations were removed.

- Condition 4.1.4 was revised to include emission calculations for methanol.

- The language in Condition 4.1.5 was revised to remove references to the single and total HAP limits and to require that ethylene glycol and methanol emissions be included in the VOC emission calculations.

<u>Section II.5 – Fugitive emissions of VOC from equipment leaks</u>

In the May 2, 2013 submittal CIG submitted information indicating that VOC emissions from equipment leaks are below the APEN de minimis level (1 tpy of VOC) and submitted a request to cancel the underlying construction permit (95AR109). Therefore the requirements for fugitive VOC emissions from equipment leaks in Section II.5 have been removed. Fugitive VOC emissions from equipment leaks are included in the insignificant activity list in Appendix A.

<u>Section II.6 – Condensate Truck Loading</u>

Emissions from the condensate loading rack will be controlled by the flare. Therefore, in the May 2, 2103 submittal, CIG requested that the APEN for condensate loading be cancelled. Therefore, the requirements for condensate loading in Section II.6 have been removed.

<u>Other Modifications</u>

In addition to the source requested modifications, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments to the Latigo Compressor Station Renewal Operating Permit. These changes are as follows:

<u>Page Following Cover Page</u>

- Revised the permit contact.

<u>Section I – General Activities and Summary</u>

- Corrected the citation for the definition of the 8-hr ozone control area in Condition 1.1.

- Condition 1.4 was revised to remove Section IV, Condition 3.d as a state-only requirement, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

- The AOS for temporary engine replacement was included in Condition 2.

Note that the permanent AOS cannot be provided since the facility is a major stationary source for purposes of PSD and non-attainment area NSR review and none of the engines with emission limitations have permitted emissions below the significance level. The temporary AOS specifies 270 days for temporary engine replacement, since the permanent AOS cannot be provided. It is expected that if a permanent engine replacement is required that either a modified Title V permit or a construction permit can be issued within that time frame.

- The following changes were made to the table in Condition 6.1:
  - Added a column for the startup date of the equipment.
  - Combined the emission unit no. and facility id columns.
  - The second column was labeled AIRS point number as that is more appropriate.
  - The emergency generator, process heaters and cold cleaner solvent vat no longer qualify as insignificant activities and have been included in the table.
- The compliance schedule in Condition 7 was removed. The stack heights have been increased as required and the stack heights are listed in the specific sections of the permit that address the engines.

<u>Section II.1 and 2 – Engines E001 – E004</u>

- Condition 1.6 (engine operation) was added to the summary table and the text language was revised to include “good engineering practices”.
- Engine stack heights were added as Conditions 1.7 and 2.5.

<u>Section II.3 – Engines E005 and E006</u>

- Revisions were made to the RICE MACT (40 CFR Part 63 Subpart ZZZZ) on August 20, 2010 and these revisions apply to these engines. The appropriate applicable requirements from the RICE MACT were included in Condition 3.4. Note that these engines are subject to formaldehyde limits.

  Under the RICE MACT these engines are subject to formaldehyde emission limitations and most likely the engines will comply with the emission limitations without installing controls. The RICE MACT requires an initial performance test to demonstrate compliance with the emission limitations but does not require subsequent tests. In addition, the RICE MACT does not require monitoring of any operating parameters. Since the RICE MACT only requires a one-time performance test, the Division will require that subsequent performance tests be conducted every five years to satisfy the Title V periodic monitoring requirements.

- Engine stack heights were added as Condition 3.5.

Section II.4 – Glycol Dehydrator

- The Natural Gas Transmission and Storage MACT requirements have been included in Condition 4.4 of the permit.

  Note that under the revisions to Subpart HHH, the unit is subject to a unit specific BTEX emission limitation. Compliance with the unit specific emission limitation may be met by connecting the process vent to a control device through a closed vent system, process modifications, combination of process modifications and control device and actual uncontrolled emissions. Since the source is currently uncontrolled and emissions indicate that the unit can comply with the unit specific BTEX limitation without installing controls, the permit includes the option for actual, uncontrolled emissions.

  The compliance option for actual, uncontrolled emissions in found in § 63.1275(b)(1)(iii)(D) and according to this paragraph, operation parameter have to be documented in accordance with 63.1281(e) and emissions in accordance with 63.1282(a)(3). The provisions in 63.1281(e) apply to process modifications and recording parameters for baseline operations (in order to document process modifications that reduce emissions) and the source is not relying on process modifications to meet the site-specific BTEX limit, therefore, the requirements in 63.1281(e) do not apply.

  In addition, 63.1275(b)(1)(iii)(D) refers to 63.1282(a)(3) for emissions but there is no 63.1282(a)(3) (emission calculations methods are noted in 63.1282(a)(2) and these methods are referenced in the definition of a "small unit" in 63.1271). 63.1282(c)(2) specifies the compliance demonstration method for small units that don't rely on a control device, so these requirements have been included.

  It should be noted that there appears to be errors in 63.1282(c)(2). It appears that the provisions allow compliance with the BTEX limit to be demonstrated using either a performance test (based on Method 18) or GLYCalc. However, there appears to be errors in the rule language. Specifically, the GLYCalc alternative is noted in 63.1282(c)(2)(iii) and the last sentence states that "[w]hen the BTEX mass rate is calculated for glycol dehydration units using the model GRI-GLYCalc™ , all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed" but GLYCalc does not rely on Method 18. In addition, seems to imply that if GLYCalc is used as an alternative, the dehy exhaust gas flow rate would still have to be measured but GLYCalc estimates emissions based on inlet parameters and there is no need to measure the exhaust rate. Therefore, this condition has been written to stipulate that compliance will be demonstrated based on either performance test methods or GLYCalc.

  In addition, it is not clear from the language in 63.1283(c)(2) whether the compliance demonstration is to be made annually or is a one-time demonstration. Language will be included in indicate that the permittee shall be required to do all of the following on an annual basis: demonstrate that the unit meets the definition of a "small" glycol dehydrator, calculate the site specific BTEX limit and demonstrate that the site-specific BTEX limit has been met.

"New" Section II.8 – Emergency Generator

There is one engine included in the insignificant activity list that was considered insignificant under the provisions in Colorado Regulation No. 3, Part C, Sections II.E.3.nnn (emergency generators). However, under the "catch-all" provisions in Regulation No. 3, Part C, Section II.E, sources that are subject to any federal or state applicable requirement, such as National Emission Standards for Hazardous Air Pollutants (NESHAPs), may not be considered insignificant activities. EPA promulgated National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines on August 20, 2010 which apply to this engine; therefore, it can no longer be considered an insignificant activity. Although the unit cannot be considered an insignificant activity, since the Division has not adopted revisions to the RICE MACT, promulgated after July 1, 2007, this engine is still exempt from APEN reporting and minor source construction permit requirements, provided actual, uncontrolled emissions do not exceed the APEN de minimis level. The source submitted information indicating that this engine is still APEN exempt.

The engine description is as follows:

Waukesha, Model No. F1197, emergency generator engine, rated at 225 hp and 2.0 MMBtu/hr. Serial No. 289938. Natural gas fired, 4-cycle rich burn engine.

The appropriate applicable requirements for this engine are as follows:

- Except as provided for below, visible emissions shall not exceed 20% opacity (Reg 1, Section II.A.1)

- Visible emissions shall not exceed 30% opacity, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment, when burning coal (Reg 1, Section II.A.4)

  Based on engineering judgment, the Division believes that the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to engines. In addition, since this engine is not equipped with control equipment the operational activities of adjustment or occasional cleaning of control equipment also do not apply to this engine. Process modifications and startup may apply to engines, however, based on engineering judgment, the Division believes that such activities would be unlikely to occur for longer than six minutes. Therefore, the 30% opacity requirement has not been included in the operating permit.

- 40 CFR Part 63 Subpart ZZZZ requirements – management practices (oil and filter change, inspect spark plugs and inspect hoses and belts)

- 40 CFR Part 63 Subpart A requirements

  Since this engine is not subject to any emission limitations, monitoring requirements, notification and reporting requirements the requirements in §§ 63.7. 63.8, 63.9 and 63.10 do not apply. In addition, since this emission unit is existing the requirement in § 63.5 (preconstruction review and notification requirements) do not apply. Finally, Table 8 of Subpart ZZZZ indicates that operation and maintenance requirements in 63.6(e) do not apply. Therefore, the permit will only include the prohibition and circumvention requirements in § 63.4.

Since this unit is not subject to APEN reporting or minor source construction permit requirements, the permit will not include any requirements for calculating emissions.

<u>"New" Section II.9 – Boilers and Process Heaters</u>

Since the facility is a major source for HAP emissions the equipment at this facility is subject to the Boiler MACT requirements. There are no boilers and process heaters included in Section II of the current permit but as indicated previously, there is no de minimis level for affected facilities under the Boiler MACT. Therefore, any boilers or process heaters identified in the insignificant activity list would be subject to the Boiler MACT requirements. As discussed above for the emergency generator, under the "catch-all" provisions in Regulation No. 3, Part C, Section II.E, sources that are subject to any federal or state applicable requirement, such as NESHAPs or MACT requirements, may not be considered insignificant activities.

The insignificant activity lists a boiler and a number of heaters that may be subject to the Boiler MACT requirements (40 CFR Part 63 Subpart DDDDD). CIG submitted information on May 2, 2013 indicating the fuel burning equipment located at the facility and the purpose of the equipment (e.g. comfort heater). In their May 2, 2013 submittal, CIG indicated that the Peerless boiler does not meet the definition of a boiler because it does not have "the primary purpose of recovering thermal energy in the form of steam or water" and is not considered process heater since it is used for comfort heat. Most of the heaters at the facility are used for comfort heat. The definition of process heater in § 63.7575 excludes units used for comfort or space heat. One heater was defined as a hot water heater and hot water heaters less than 120 gallons are not subject to the requirements in Subpart DDDDD in accordance with § 63.7491(d).

In the May 2, 2013 submittal, CIG identified the twenty five (25) well head heaters, the heater treater and the glycol dehydrator reboiler as process heaters. The Division considers that the glycol dehydrator reboiler is not subject to the requirements in Subpart DDDDD since it is part of an affected facility that is subject to another MACT standard as provided for in 40 CFR Part 63 Subpart DDDDD § 63.7491(h). Glycol dehydrators are an affected facility subject to the requirements in 40 CFR Part 63 Subpart HHH (NGTS MACT) which applies to NGTS facilities that are major sources for HAPs. Therefore, the twenty five well head heaters (each rated at 1 MMBtu/hr) and the heater treater (rated at 0.5 MMBtu/hr) are subject to the requirements in Subpart DDDDD and can no longer be considered insignificant activities.

The process heaters subject to the following applicable requirements:

- Except as provided for below, visible emissions shall not exceed 20% opacity (Reg 1, Section II.A.1)

- Visible emissions shall not exceed 30% opacity, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)

  Based on engineering judgment, the Division believes that the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to these units. In addition, since these units are not equipped with control equipment the operational activities of adjustment or occasional cleaning of control equipment also do not apply to these units. Process modifications and startup may apply to these units, however, based on engineering judgment, the Division believes that such activities would be unlikely to occur for longer than six minutes. Therefore, the 30% opacity requirement has not been included in the operating permit.

- Particulate matter emissions shall not 0.5 lbs/MMBtu (Reg 1, Section III.A.1.a)

- Boiler MACT requirements (40 CFR Part 63 Subpart DDDDD), which include the following:

  - One-time energy assessment

  - Heater tune-ups every five years

Since these units are not subject to APEN reporting or minor source construction permit requirements, the permit will not include any requirements for calculating emissions.

<u>“New” Section II.10 – Cold Cleaner Solvent Vat</u>

A degreaser is included in the list of insignificant activities in Appendix A of the permit. Colorado Regulation No. 7 was revised on December 12, 2008 (effective January 30, 2009) to cover all ozone nonattainment areas (previously Reg 7 applied to the Denver 1-hr ozone attainment maintenance area and to any non-attainment area for the 1-hr ozone standard) and as a result the requirements in Colorado Regulation No. 7, Section X apply to the degreaser. Although emissions from this degreaser are below the APEN de minimis level and exempt from APEN reporting and the minor source construction permit requirements, it is subject to specific requirements in Colorado Regulation No. 7, Section X. Therefore, under the “catch-all” provisions in Regulation No. 3, Part C, Section II.E (2nd paragraph) the solvent vat cannot be considered an insignificant activity because it is subject to specific requirements in Regulation No. 7. Since the degreaser cannot be considered an insignificant activity, the degreaser has been removed from the insignificant activity list and it has been included in Section II.10 of the permit. The appropriate applicable requirements for this unit are as follows:

- Transfer and storage of waste solvent and used solvent (Reg 7, Sections X.A.3 and 4)

- Solvent Cold Cleaner Requirements (Reg 7, Section X.B)

    - Control Equipment - covers, drainage, labeling and spray apparatus requirements (Reg 7, Section X.B.1)
    - Operating Requirements (Reg 7, Section X.B.2)

<u>Section IV – General Conditions</u>

- Added a version date.

- The paragraph in Condition 3.d indicating that the requirements are state-only has been removed, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

- The title for Condition 6 was changed from "Emission Standards for Asbestos" to "Emission Controls for Asbestos" and in the text the phrase "emission standards for asbestos" was changed to "asbestos control"

- Condition 29 (VOC) was revised primarily to add the provisions in Reg 7, Section III.C as paragraph e although other minor language and format changes were made.

<u>Appendices</u>

- The following changes were made to the insignificant activity list in Appendix A:

    - Grouped activities by the insignificant activity categories and noted those categories for which records should be available to verify insignificant activity status.
    - Removed the degreaser, emergency generator, wellhead heaters and heater treater since these units can no longer be considered insignificant activities.

    - Based on comments from the source submitted on September 27, 2013, the 3,780 gallon oil/water tank was removed from the list.

- The tables in Appendices B and C were revised to include the emergency generator, process heaters and cold cleaner solvent vat. In addition, the name change to "Colorado Interstate Gas Company, LLC" was reflected in Appendices B and C.

- Added the Division contact for reports in Appendix D.

- Cleared the table in Appendix F.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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JUN 28 2004
APCO
Stationary
Sources

JUN 24 2004

Ref: 8ENF-AT

James A. King, Manager
Operating Permit Unit
Stationary Sources Program
Air Pollution Control Division
Colorado Department of Health & Environment
4300 Cherry Creek Drive South
Denver, CO 80222-1530

Re: Applicability Determination in Clarifying the Natural Gas Processing Plant Definition Under NSPS Subpart KKK

Dear Mr. King:

This letter is in response to your August 14, 2003 request for the Environmental Protection Agency (EPA) to clarify whether natural gas storage facilities that inject processed natural gas (i.e. liquids have been extracted) into depleted gas/oil wells or other underground caverns and then extract natural gas liquids from the gas upon withdrawal are a "natural gas processing plant" as defined under New Source Performance Standards for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (NSPS Subpart KKK). Since your request, EPA Region 8 and EPA Headquarters have had numerous discussions regarding this determination. In the next paragraph EPA Headquarters' position is summarized.

NSPS Subpart KKK applies to affected facilities in onshore natural gas processing plants. A natural gas processing plant (gas plant) is defined as "any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both." Field gas is defined as "feedstock gas entering the natural gas processing plant." While feedstock gas is not defined, the Agency provides further clarification of the definition of field gas in the National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities (MACT Subpart HH). MACT Subpart HH defines "Field natural gas" as "natural gas extracted from a production well prior to entering the first stage of processing, such as dehydration." As stated above, the facility in question injects processed gas into underground caverns. Since the field gas or feedstock gas is processed prior to being stored in the underground caverns it is no longer field gas when the facility further processes the gas to remove impurities. Consequently, the facility does not meet the definition of "natural gas processing plant" in NSPS Subpart KKK since they are not extracting natural gas liquids from field gas, nor are they conducting fractionation of mixed natural gas liquids to

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natural gas products. Therefore, NSPS Subpart KKK would not apply to natural gas storage facilities that inject processed natural gas into depleted gas/oil wells or other underground caverns and then extract natural gas liquids from the gas upon withdrawal.

However, as a practical matter, Region 8 believes that NSPS KKK should apply to these facilities because the processed natural gas is re-treated when it is withdrawn from the caverns. When it is being re-treated, we would like the records required by Section 60.635 to be kept in order to assure that the volatile organic compound (VOC) content is not above 10% by weight, meaning that the facility is not "in VOC service". NSPS KKK does not explicitly exempt re-treatment of processed natural gas. The MACT HH regulations clarify the definition of field gas for purposes of that regulation and do not indicate that the clarified definition is applicable to NSPS KKK. Region 8 is requesting that EPA Headquarters clarify the NSPS KKK regulations to explicitly include these facilities.

Region 8 also believes that Colorado has the authority under its State Implementation Plan to regulate these types of facilities. This would be appropriate as these natural gas storage facilities may have the potential to emit a significant amounts of VOCs.

If you have any questions, the most knowledgeable people on my staff are Martin Hestmark, Program Director, Technical Enforcement Program at (303) 312-6776 and Cindy Reynolds at (303) 312-6206.

Sincerely,

Michael T. Risner for

Carol Rushin
Assistant Regional Administrator
Office of Enforcement, Compliance
and Environmental Justice

cc: Hans Buenning, 8P-AR
Maria Malave, OECA
David Markwordt, OAQPS
Rick Vetter, OGC

2

Facility Wide HAP Emissions

	HAP Emissions (tons/yr)										
Unit	acetaldehyde	acrolein	benezene	toluene	ethyl benzene	xylene	formaldehyde	ethylene glycol	n-hexane	methanol	**total**
E001	3.04E-01	2.06E-01	5.37E-02	2.78E-01		1.45E-02	1.61		4.04E-02	9.09E-02	2.60
E002	3.04E-01	2.06E-01	5.37E-02	2.78E-01		1.45E-02	1.61		4.04E-02	9.09E-02	2.60
E003	3.04E-01	2.06E-01	5.37E-02	2.78E-01		1.45E-02	1.61		4.04E-02	9.09E-02	2.60
E004	2.75E-01	1.86E-01	4.84E-02	2.50E-01		1.30E-02	1.45		3.65E-02	8.21E-02	2.34
E005	3.67E-02	3.46E-02	8.54E-02	2.74E-02		6.18E-03	0.38			4.02E-02	0.61
E006	3.67E-02	3.46E-02	8.54E-02	2.74E-02		6.18E-03	0.38			4.02E-02	0.61
E007 (emerg. gen)	1.37E-03	1.29E-03	7.74E-04	8.80E-04		1.98E-04	1.23E-02			1.50E-03	0.02
Dehy			1.19	2.05	0.66	1.15		1.05	0.15	1.80	8.05
Flare			6.26E-03	8.44E-03	1.09E-03	6.26E-03			3.85E-02		0.06
Evap Ponds			7.10E-03	1.80E-02	2.50E-03	2.12E-03				51.70	51.73
Heaters			2.27E-04				9.72E-03		2.33E-01		0.24
Total	1.26	0.87	1.58	3.22	0.66	1.23	7.07	1.05	0.58	53.94	71.46

Engine emissions are based on most conservative emission factor (from AP-42 and HAPCalc 2.0, for 4-cycle rich burn engines or performance test conducted July 2004 for engines E001 - E004) for each pollutant. Note that the GRI HAPCal version 2.0 factors are not significantly different from HAPCalc version 3.0 factors. Emissions from the emergency generator are based on 500 hrs/yr of operation, for other engines emissions are based on 8760 hrs/yr of operation.

Dehy emissions based on GLYCalc run used to set permit limits. Emissions of methanol and ethylene glycol are based on stack test emission factors and permitted hours of operation.

Emissions from the Evap Ponds are based on information in the April 3, 2012 additional information submittal. Note that beginning with the 2013 withdrawal season produced water will be sent to an injection well, so emissions will be negligible. However, CIG requested one pond be used for back-up purposes, so emissions from the pond have been assessed.

Emissions from the heaters are based on AP-42 emission factors, design rate and 8760 hrs/yr of operation.

Emissions from the flare are based on the December 27, 2012 information submittal.